2002 Final Power Rate Proposal
Risk Analysis Study

WP-02-FS-BPA-03
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BONNEVILLE
POWER ADMINISTRATION

2002 RISK ANALYSIS STUDY

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COMMONLY USED ACRONYMS

AANR	Audited Accumulated Net Revenues
AC	Alternating Current
AER	Actual Energy Regulation
Affiliated Tribes	Affiliated Tribes of Northwest Indians
AFUDC	Allowance for Funds Used During Construction
AGC	Automatic Generation Control
Alcoa	Alcoa, Inc.
Alcoa/Vanalco	Joint Alcoa and Vanalco
aMW	Average Megawatt
ANRT	Accumulated Net Revenue Threshold
AOP	Assured Operating Plan
APS	Ancillary Products and Services (rate)
APS-S	Actual Partial Service-Simple
ASC	Average System Cost
Avista	Avista Corp
BASC	BPA Average System Cost
BO	Biological Opinion
BPA	Bonneville Power Administration
BP EIS	Business Plan Environmental Impact Statement
Btu	British Thermal Unit
C&R Discount	Conservation and Renewables Discount
C&R	Cost and Revenue
CalPX	California Power Exchange
CBFWA	Columbia Basin Fish & Wildlife Authority
CBP	Columbia Basin Project
CCCT	Combined-Cycle Combustion Turbine
CEC	California Energy Commission
CFAL	Columbia Falls Aluminum Company
Cfs	cubic feet per second
COB	California-Oregon Border
COE	U.S. Army Corps of Engineers
Con/Mod	Conservation Modernization Program
COSA	Cost of Service Analysis
CP	Coincidental Peak
CRAC	Cost Recovery Adjustment Clause
CRC	Critical Rule Curves
CRITFC	Columbia River Inter-Tribal Fish Commission
CSPE	Columbia Storage Power Exchange
CT	Combustion Turbine
CTPP	Conditional TPP
CWA	Clear Water Act
CY	Calendar Year (Jan-Dec)
DC	Direct Current

DDC	Dividend Distribution Clause
DJ	Dow Jones
DMP	Data Management Procedures
DOE	Department of Energy
DROD	Draft Record of Decision
DSI	DSI (only the DSI represented by Murphy under DS)
DSIs	Direct Service Industrial Customers
ECC	Energy Content Curve
EFB	Excess Federal Power
EIA	Energy Information Administration
EIS	Environmental Impact Statement
Energy Northwest	Formerly Washington Public Power Supply System (Nuclear) Project
Energy Services	Energy Services, Inc.
Enron	Enron Corporation
EPA	Environmental Protection Agency
EPP	Environmentally Preferred Power
ESA	Endangered Species Act
EWEB	Eugene Water & Electric Board
F&O	Financial and Operating Reports
FBS	Federal Base System
FCCF	Fish Cost Contingency Fund
FCRPS	Federal Columbia River Power System
FCRTS	Federal Columbia River Transmission System
FELCC	Firm Energy Load Carrying Capability
FERC	Federal Energy Regulatory Commission
Fourth Power Plan	NWPPC’s Fourth Northwest Conservation and Electric Power Plan
FPA	Federal Power Act
FPS	Firm Power Products and Services (rate)
FSEA	Federal Secondary Energy Analysis
F&WCA	Fish and Wildlife Coordination Act
FY	Fiscal Year (Oct-Sep)
GCPs	General Contract Provisions
GEP	Green Energy Premium
GI	Generation Integration
GRI	Gas Research Institute
GRSPs	General Rate Schedule Provisions
GSP	Generation System Peak
GSU	Generator Step-Up Transformers
GTA	General Transfer Agreement
GWh	Gigawatthour
HELM	Hourly Electric Load Model
HLFG	High Load Factor Group
HLH	Heavy Load Hour
HNF	Hourly Non-Firm
HOSS	Hourly Operating and Scheduling Simulator

ICNU	Industrial Customers of Northwest Utilities
ICUA	Idaho Consumer-Owned Utilities Association, Inc.
IPC	Idaho Power Company
IP	Industrial Firm Power (rate)
IPTAC	Industrial Firm Power Targeted Adjustment Charge
IJC	International Joint Commission
IOU	IOU (the joint IOU filings)
IOUs	Investor-Owned Utilities
ISC	Investment Service Coverage
ISO	Independent System Operator
JOA	Joint Operating Agency
Joint DSI	Alcoa, Vanalco, and DSI
KAF	Thousand Acre Feet
kcfs	kilo (thousands) of cubic feet per second
ksfd	thousand second foot day
kV	Kilovolt (1000 volts)
kW	Kilowatt (1000 watts)
kWh	Kilowatthour
LCP	Least-Cost Plan
LDD	Low Density Discount
LLH	Light Load Hour
LME	London Metal Exchange
LOLP	Loss of Load Probability
L/R Balance	Load/Resource Balance
m/kWh	Mills per kilowatthour
MAC	Market Access Coalition Group
MAF	Million Acre Feet
MC	Marginal Cost
MCA	Marginal Cost Analysis
MCS	Model Conservation Standards
Mid-C	Mid-Columbia
MIMA	Market Index Monthly Adjustment
MIP	Minimum Irrigation Pool
MMBTU	Million British Thermal Units
MOA	Memorandum of Agreement
MOP	Minimum Operating Pool
MORC	Minimum Operating Reliability Criteria
MPC	Montana Power Company
MT	Market Transmission (rate)
MW	Megawatt (1 million watts)
MWh	Megawatthour
NCD	Non-coincidental Demand
NEC	Northwest Energy Coalition
NEPA	National Environmental Policy Act
NEPOOL	New England Power Pool

NERC	North American Electric Reliability Council
NF	Nonfirm Energy (rate)
NFRAP	Nonfirm Revenue Analysis Program (model)
NLSL	New Large Single Load
NMFS	National Marine Fisheries Service
NOB	Nevada-Oregon Border
NORM	Non-Operating Risk Model
Northwest Power Act	Pacific Northwest Electric Power Planning and Conservation Act
NPV	Net Present Value
NR	New Resource Firm Power (rate)
NRU	Northwest Requirements Utilities
NT	Network Transmission
NTP	Network Integration Transmission (rate)
NTSA	Non-Treaty Storage Agreement
NUG	Non-Utility Generation
NWPP	Northwest Power Pool
NWPPC C&R	Northwest Power Planning Council Cost and Revenues Analysis
NWPPC	Northwest Power Planning Council
O&M	Operation and Maintenance
OMB	Office of Management and Budget
OPUC	Oregon Public Utility Commission
OURCA	Oregon Utility Resource Coordination Association
OY	Operating Year (Aug-Jul)
PA	Public Agency
PacifiCorp	PacifiCorp
PATH	Plan for Analyzing and Testing Hypotheses
PBL	Power Business Line
PDP	Proportional Draft Points
PDR	Power Discharge Requirement
PF	Priority Firm Power (rate)
PFBC	Pressurized Fluidized Bed Combustion
PGE	Portland General Electric
PGP	Public Generating Pool
PMA	Power Marketing Agencies
PMDAM	Power Marketing Decision Analysis Model
PNCA	Pacific Northwest Coordination Agreement
PNGC	Pacific Northwest Generating Cooperative
PNRR	Planned Net Revenues for Risk
PNUCC	Pacific Northwest Utilities Conference Committee
PNW	Pacific Northwest
POD	Point of Delivery
PPC	Public Power Council
PPLM	PP&L Montana, LLC
Principles	Fish and Wildlife Funding Principles
Project Act	Bonneville Project Act

PSE	Puget Sound Energy
PSW	Pacific Southwest
PTP	Point-to-Point
PUD	Public or People's Utility District
Puget	Puget Sound Energy, Inc.
PURPA	Public Utilities Regulatory Policies Act
RAM	Rate Analysis Model (computer model)
RAS	Remedial Action Scheme
Reclamation	Bureau of Reclamation
Renewable Northwest	Renewable Northwest Project
REP	Residential Exchange Program
RFP	Request for Proposal
RiskMod	Risk Analysis Model (computer model)
RiskSim	Risk Simulation Model
RL	Residential Load (rate)
RMS	Remote Metering System
ROD	Record of Decision
RPSA	Residential Purchase and Sale Agreement
RTF	Regional Technical Forum
RTO	Regional Transmission Organization
SCCT	Single-Cycle Combustion Turbine
Shoshone-Bannock	Shoshone-Bannock Tribes
SOS	Save Our Wild Salmon
SPG	Slice Purchasers Group
SS	Share-the-Savings Energy (rate)
STREAM	Short-Term Evaluation and Analysis Model
SUB	Springfield Utility Board
SUMY	Stepped-Up Multiyear
SWPA	Southwestern Power Administration
TAC	Targeted Adjustment Charge
TACUL	Targeted Adjustment Charge for Uncommitted Loads
TBL	Transmission Business Line
tcf	Trillion Cubic Feet
TCH	Transmission Contract Holder
TDG	Total Dissolved Gas
TPP	Treasury Payment Probability
Transmission System Act	Federal Columbia River Transmission System Act
TRL	Total Retail Load
UAI Charge	Unauthorized Increase Charge
UAMPS	Utah Associated Municipal Power Systems
UCUT	Upper Columbia United Tribes
UDC	Utility Distribution Company
UP&L	Utah Power & Light
URC	Upper Rule Curve
USFWS	U.S. Fish and Wildlife Service

Vanalco	Vanalco, Inc.
VB	Visual Basic
VBA	Visual Basic for Applications
VI	Variable Industrial Power rate
VOR	Value of Reserves
WAPA	Western Area Power Administration
WEFA	WEFA Group (Wharton Econometric Forecasting Associates)
WPAG	Western Public Agencies Group
WPRDS	Wholesale Power Rate Development Study
WSCC	Western Systems Coordinating Council
WSPP	Western System Power Pool
WUTC	Washington Utilities and Transportation Commission
WY	Watt-Year
Yakama	Confederated Tribes and Bands of the Yakama Nation

1. INTRODUCTION

1.1 Background

The electric utility industry is in the midst of deregulation. The Federal Columbia River Power System (FCRPS), operated on behalf of the ratepayers of the Pacific Northwest (PNW) by the Bonneville Power Administration (BPA) and other Federal agencies, faces many uncertainties during the Fiscal Year (FY) 2002 - 2006 rate period. Among these uncertainties are variable hydro conditions, volatile market prices, and uncertain fish and wildlife recovery costs. BPA must produce revenues from wholesale power rates that are sufficient to cover all its costs during the rate period. These costs include expenses related to recovery efforts for fish and wildlife, which have been impacted by the presence of Federal dams on the rivers and streams of the Columbia River Basin. The expenses associated with these fish and wildlife recovery efforts, in turn, impact BPA's ability to make its annual payments to the U.S. Treasury.

In order to assure that BPA has a high probability of making its annual Treasury payments on time and in full during the rate period, BPA performs a Risk Analysis Study. In this Study, BPA identifies key risks, models their relationships, and then analyzes their impacts on net revenues (revenues less expenses). BPA subsequently evaluates the impact that certain risk mitigation measures have on reducing its net revenue risk so that BPA can develop rates that cover all its costs and provide a high probability of making its Treasury payments on time and in full during the rate period.

In this rate case, BPA is setting its power rates so that it achieves an 88 percent probability that all Treasury payments will be made on time and in full over the five-year rate period. To accomplish this task, it is necessary to quantify and then mitigate key operating and non-operating risks. The first step in this process is the Risk Analysis Study, which identifies key risk factors, models the relationship among the risk factors, and determines their impacts on net revenues.

1.2 Overview

The Risk Analysis Study focuses upon two classes of risks and their impacts on BPA's revenues and expenses. The first class of risks is comprised of **operating risks** - variations in economic conditions, load, and generation resource capability. These operating risks include both the impacts that water supply conditions and alternative hydro operations (including the impact of the 13 Fish and Wildlife Alternatives) have on net revenues. These operating risks are modeled in Risk Analysis Model (RiskMod). The second class of risks is comprised of **non-operating risks** - uncertainties in capital costs and expenses (but not operational impacts) associated with the 13 Fish and Wildlife Alternatives identified in the Fish and Wildlife Funding Principles (Principles) announced by Vice President Gore in September 1998. This class of non-operating risks also includes uncertainty in achieving cost reductions identified in the Cost Review recommendations, costs associated with business line separation, costs associated with conservation and renewables, and interest rates. These risks are modeled in the Non-Operating Risk Model (NORM). The output from RiskMod and NORM is combined to develop a distribution of net revenue deviations that are input into the ToolKit Model. The ToolKit Model uses the net revenue data to test the effectiveness of implementing various risk mitigation measures in order to meet BPA's Treasury Payment Probability (TPP) standard.

The ToolKit Model assesses the impact that the net revenue deviations have on cash reserve levels, calculates the probability that BPA will make its Treasury payments on time and in full, and determines the combination of risk mitigation tools (*e.g.,* Cost Recovery Adjustment Clause

(CRAC), Planned Net Revenues for Risk (PNRR), etc.) that are needed to meet BPA's 88 percent TPP standard. The amount of PNRR calculated by the ToolKit Model is added to the Revenue Requirement in the Rate Analysis Model (RAM) and, thus, impacts the level of the rates calculated by RAM.

BPA included the full range of potential fish and wildlife costs in a manner consistent with the Principles. These costs consist of operational impact costs, expenses, capital costs, and BPA direct program operations and maintenance (O&M). BPA modeled the operational impact costs in RiskMod and the expenses, capital costs, and BPA direct program O&M in NORM. Consistent with the Principles, BPA direct program O&M was modeled in NORM to range from $100 to $179 million. Also, as specified in the Principles, BPA treated each of the 13 Fish and Wildlife Alternatives as equally likely to occur.

The Risk Analysis Study explores the hydrosystem operation implications and net revenue impacts for each of the 13 Fish and Wildlife Alternatives. These 13 Fish and Wildlife Alternatives include five Fish and Wildlife Alternatives that involve the breaching of dams. These five Alternatives include both adjusted and unadjusted schedule variants, for a total of 18 fish and wildlife scenarios.

Both RiskMod and NORM use the same general simulation methodology and @RISK computer software package to assess the impacts of a distribution of risk factors on net revenues (RiskMod) or anticipated costs (NORM). RiskMod quantifies the operating risks associated with loads and resources performance for California, the PNW, and the Federal system, in addition to those risks associated with natural gas prices. The 13 Fish and Wildlife Alternatives affect hydro performance through the changes in operations that they require. NORM measures the uncertainty surrounding the non-operating costs of the 13 Fish and Wildlife Alternatives and develops distributions of projected costs for each of the 18 fish and wildlife scenarios.

Chapter 2 of this Study describes the operation of the RiskMod Model and its quantification of operating risks. Chapter 3 describes the operation of the NORM Model and its use in assessing non-operating risks. Section 2.2 of the Revenue Requirement Study, WP-02-FS-BPA-02, describes how the results of the Risk Analysis Study are used to assess risk mitigation measures (*i.e.*, develop the level of the CRAC and the amount of PNRR that is included in the Revenue Requirement). A more detailed description of the ToolKit Model is found in Volume 1, Chapter 12 of Revenue Requirement Study Documentation, WP-02-FS-BPA-02A. Further discussion of the RAM can be found in the Wholesale Power Rates Development Study, WP-02-FS-BPA-05.

2. ANALYSIS OF OPERATING RISK

2.1 RiskMod

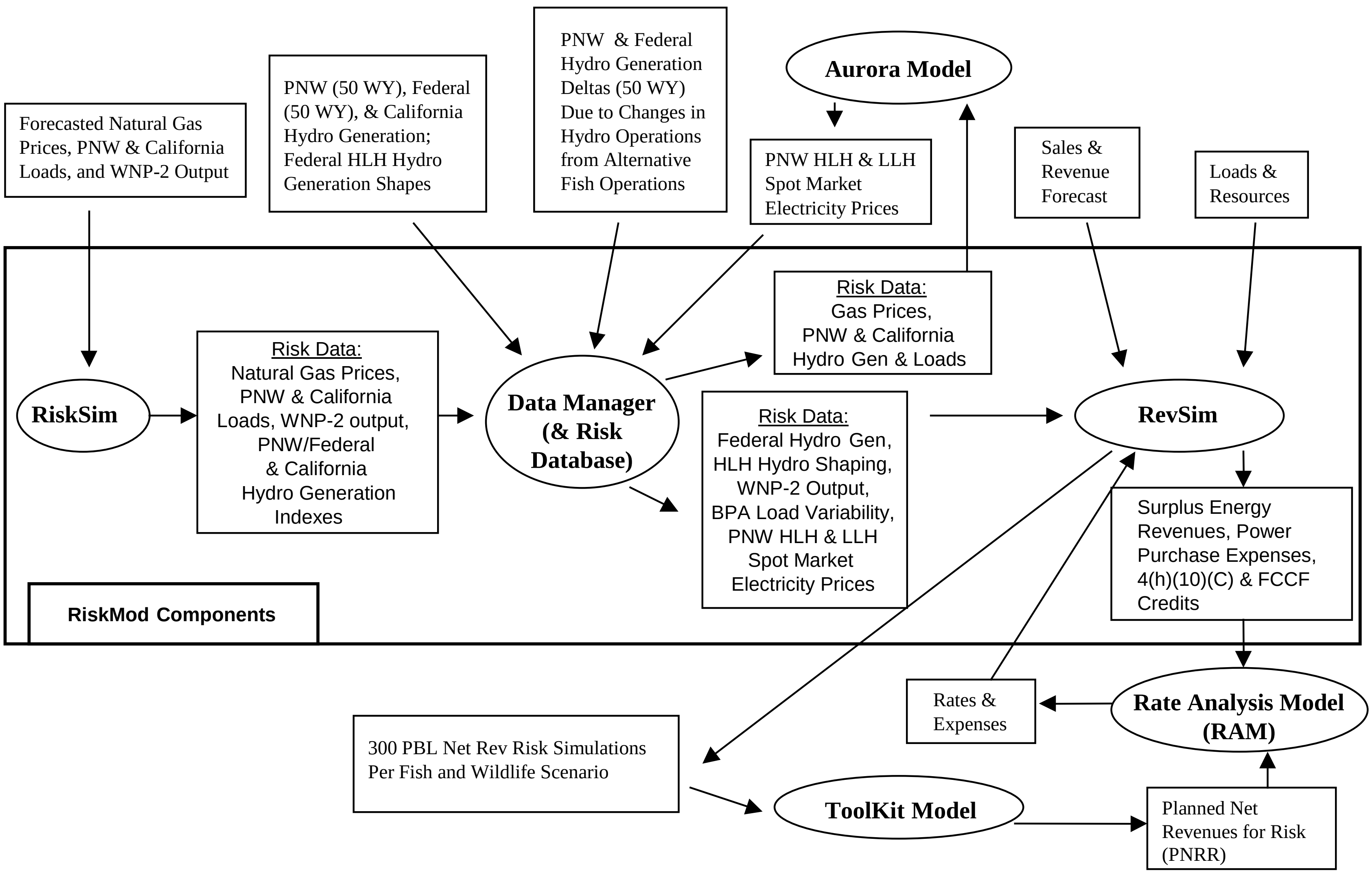
The RiskMod Model is comprised of a set of risk simulation models collectively referred to as RiskSim; a computer program that manages data referred to as Data Manager; and RevSim, a model that calculates net revenues. RiskMod interacts with AURORA, the RAM, and the ToolKit Model during the process of performing the Risk Analysis Study. AURORA is the computer model being used to perform the Marginal Cost Analysis (*see* Marginal Cost Analysis Study, WP-02-FS-BPA-04), the RAM is the computer model being used to calculate rates (*see* Wholesale Power Rate Development Study, WP-02-FS-BPA-05), and the ToolKit is the computer model being used to calculate PNRR to achieve BPA’s TPP standard. (*See* Volume 1, Section 12 of Revenue Requirement Study Documentation, WP-02-FS-BPA-02A.)

Variations in monthly loads, resources, and natural gas prices are simulated in RiskSim. Monthly spot market electricity prices for the simulated loads, resources, and natural gas prices are estimated by the AURORA Model. The Data Manager facilitates the format and movement of data that flow to and/or from RiskSim, AURORA, and RevSim. RevSim uses risk data from RiskSim, spot market electricity prices from AURORA, loads and resources data from the Loads and Resources Study, WP-02-FS-BPA-01, various revenues from the Revenue Forecast component of the Wholesale Power Rate Development Study, WP-02-FS-BPA-05, and rates and expenses from the RAM to estimate net revenues. Annual average surplus energy revenues, purchased power expenses, section 4(h)(10)(C) credits, and Fish Cost Contingency Fund (FCCF) credits calculated by RevSim are used in the Revenue Forecast and the RAM. Net revenues estimated for each simulation by RevSim are input into the ToolKit Model to calculate PNRR. The processes and interaction between each of the models and studies are depicted in Graph 1. Additional discussion on these processes and interactions are provided in the Risk Analysis Study Documentation, WP-02-FS-BPA-03A.

2.2 Risk Simulation Models (RiskSim)

To quantify the effects of operational risks, BPA developed risk models that combine the use of logic, econometrics, and probability distributions to quantify the ordinary operational risks that BPA faces. Econometric modeling techniques were used to capture the dependency of values through time. Parameters for the probability distributions were developed from historical data. The values sampled from each probability distribution reflect their relative likelihood of occurrence and are deviations from the base case values used in the Revenue Forecast and AURORA Model.

Graph 1: RiskMod Risk Analysis Information Flow



The output from these risk models were accumulated in a computer file to form a risk data base which contains values lower than, higher than, or equal to the base case values used in the Revenue Forecast and AURORA Model. Loads, resources, and natural gas price risk data for each simulation were input into the AURORA Model to estimate heavy load hour (HLH) and light load hour (LLH) spot market electricity prices. The AURORA prices were then downloaded into the risk data base and a consistent set of loads, resources, and spot market prices were used to calculate net revenues in RevSim.

2.3 @RISK Computer Software

The risk models developed to perform the risk factor analyses were developed in the @RISK computer software package. This software is an add-in computer package to Microsoft Excel and is available from Palisade Corporation. @RISK allows statisticians to develop models incorporating uncertainty in a spreadsheet environment. Uncertainty is incorporated by specifying the type of probability distribution that best reflects the risk, providing the necessary parameters required for developing the probability distribution, and letting @RISK sample values from the probability distributions based on the parameters provided. The values sampled from the probability distributions reflect their relative likelihood of occurrence. The parameters required for appropriately capturing risk are not developed in @RISK, but are developed in analyses external to @RISK.

2.4 Operational Risk Factors

In the course of doing business, BPA manages risks that are unique to operating a hydrosystem as large as the FCRPS. The variation in hydro generation due to the volume of water supply from one year to the next can be substantial. BPA also faces other traditional operational risks that increase its risk exposure, including the following: load variability due to changes in load growth and weather; nuclear plant (WNP-2) performance; and variability in spot market electricity prices due to load, resource, and natural gas price variability. Since the 1996 rate case, there are additional risks, including the potential of lower Snake River Dams being breached and increased wholesale electricity price volatility resulting from the deregulation of the west coast wholesale electricity market, that BPA faces.

The following is a discussion of the major risk factors included in RiskMod. For discussion purposes, the various risk factors are grouped under the categories of PNW and Federal Resource Performance, PNW and BPA Loads, California Resource Performance, California Loads, and Natural Gas Prices. Each of these risk factors is used in the AURORA Model, RevSim, or both.

2.4.1 PNW and Federal Hydro Generation Risk Factors. The PNW and Federal hydro generation risk factors reflect the uncertainty that the timing and volume of streamflows have on monthly PNW and Federal hydro generation under specified hydro operation requirements. This uncertainty is accounted for by inputting monthly hydro generation data estimated by the HydroSim Model for monthly streamflow patterns experienced from August 1929 through July 1978 (also referred to as the 50 water years). These monthly hydro generation data are developed by simulating hydro operations sequentially over all 600 months of the 50 water years. This analysis by HydroSim is referred to as performing a continuous study. (*See* hydroregulation component of the Loads and Resources Study, WP-02-FS-BPA-01, regarding HydroSim and continuous study.)

The monthly Federal hydro generation data for each of the 50 water years are input into the RevSim Model to quantify the impact that Federal hydro generation variability has on BPA's net revenues. The associated monthly PNW hydro generation data for each of the 50 water years are input into the AURORA Model to quantify the impact that PNW hydro generation has on PNW spot market prices.

The PNW and Federal hydro generation data for each of the 50 water years are used to estimate prices and revenues for 300 five-year simulations (FY 2002 - 2006) for each of 13 Fish and Wildlife Alternatives. Each simulation uses a sequential set of five water years and starts each simulation using a water year randomly sampled from 1929 through 1978. When the end of the 50 water years was reached (at the end of water year 1978), monthly hydro production data for water year 1929 was subsequently used. For example, if a simulation started with water year 1977, the simulation would use water years 1977 through 1978, as well as water years 1929 through 1931, for a total of five water years. For each FY, prices and net revenues are estimated based on each of the 50 water years being sampled six times to produce 300 5-year simulations. By inputting hydro generation data in RiskMod in a continuous manner, results from the Risk Analysis are consistent with the way the data were developed in HydroSim. Using the hydroregulation data in this manner captures the dry, normal, and wet weather patterns inherent in the 50 water years and the impact that these patterns have on spot market electricity prices and BPA’s net revenues over time.

Higher streamflows usually increase surplus energy revenues and decrease purchased power expenses. Surplus energy revenues usually increase because the revenue from the larger quantities of surplus energy available for sale more than compensates for the lower market prices. Conversely, lower streamflows usually decrease surplus energy revenues and increase purchased power expenses. Surplus energy revenues usually decrease because the revenue from the smaller quantities of surplus energy available for sale are not comparably offset by higher market prices.

2.4.2 Thirteen (13) Fish and Wildlife Alternatives. Thirteen (13) Fish and Wildlife Alternatives were used during the development of the Principles, and are being used for ratesetting purposes. *See* Volume 1, Chapter 13 of Revenue Requirement Study Documentation, WP-02-FS-BPA-02A. The modeling of these Alternatives reflect the uncertainty in the operational impact that the future adoption of a specific fish and wildlife alternative might have on hydro generation. Five of these 13 Fish and Wildlife Alternatives include both adjusted and unadjusted schedule variants that reflect the uncertainty as to when the breaching of certain dams might take place. Each of the 13 Fish and Wildlife Alternatives is equally weighted, and within each of the five Fish and Wildlife Alternatives that include breaching, the unadjusted schedule is given a 10 percent probability of occurrence and the adjusted schedule is given a 90 percent probability of occurrence.

Data reflecting the impact that each of the 13 Fish and Wildlife Alternatives might have on monthly hydro generation for each of the 50 water years are obtained from hydroregulation studies performed by BPA and the Northwest Power Planning Council (NWPPC). The hydro generation impacts are measured as changes (deltas) in hydro generation relative to hydro generation for a base case hydro operation. These values, which are reported in the Risk Analysis Study Documentation, WP-02-FS-BPA-03A, are added to the PNW and Federal monthly hydro generation data produced by HydroSim for the hydroregulation component of the Loads and Resources Study, WP-02-FS-BPA-01.

Fish and Wildlife Alternatives with lower hydro generation decrease surplus energy revenues (because less surplus energy is available for sale) and increase power purchase expenses (because more power is purchased to meet firm loads). Conversely, Fish and Wildlife Alternatives that reflect higher hydro generation levels, increase surplus energy revenues (because more surplus energy is available for sale) and decrease power purchase expenses (because less power is purchased to meet firm loads).

2.4.3 Nuclear Plant Performance Risk Factor. The nuclear plant performance risk factor reflects the uncertainty in the amount of energy generated by the WNP-2 nuclear plant. Nuclear plant performance risk is modeled such that the average of the simulated outcomes is equal to the expected monthly WNP-2 output specified in the Loads and Resources Study, WP-02-FS-BPA-01. The potential values of the results simulated can vary from the output capacity of the plant to zero output.

Higher than expected nuclear plant performance either increases BPA's surplus energy revenues or reduces its power purchase expenses, because more energy is available for either making surplus energy sales or displacing power purchases. Lower than expected nuclear plant performance either decreases BPA's surplus energy revenues or increases its power purchase expenses, because less energy is available for either making surplus energy sales or displacing power purchases.

2.4.4 PNW and BPA Loads Risk Factor. This factor reflects the impact that variations in economic and weather conditions have on HLH and LLH spot market prices and Priority Firm Power (PF) loads. The level of economic activity impacts the overall annual amount of load placed on BPA by its PF customers while fluctuations in load due to weather conditions cause monthly variation in loads, especially during the winter when heating loads are highest. Load growth variability for the PNW (and indirectly for BPA) is simulated using annual variability parameters that were used as input data in the Power Market Decision Analysis Model (PMDAM) in the 1996 rate case. *See* Marginal Cost Analysis Study Documentation, WP-96-FS-BPA-04A. Monthly load variability for the PNW (and indirectly for BPA) is derived from daily load variability parameters that were used as input data in PMDAM in the 1996 rate case. *See* Marginal Cost Analysis Study Documentation, WP-96-FS-BPA-04A.

Higher than expected firm loads due to economic and weather conditions increase PF loads and revenues, increase power purchase expenses, and reduce surplus energy revenues. Lower than expected firm loads reduce PF loads and revenues, decrease power purchase expenses, and increase surplus energy revenues. Higher spot market electricity prices increase both BPA's surplus revenues and power purchase expenses. Conversely, lower spot market electricity prices decrease both BPA's surplus revenues and power purchase expenses.

2.4.5 California Resource Performance Risk Factor. This factor reflects the uncertainty that the timing and volume of streamflows have on monthly hydro production in a given year in California. This uncertainty was derived from monthly hydro production data reported by the Energy Information Administration for 1980-1997. Higher California streamflows reduce the need to run thermal plants in California, which results in lower prices paid by California utilities for PNW surplus energy and lower prices paid by PNW utilities for purchased power from California. Conversely, lower streamflows increase the need to run thermal plants in California, which results in higher prices paid by California utilities for PNW surplus energy and higher prices paid by PNW utilities for purchased power from California.

2.4.6 California Loads Risk Factor. This factor reflects the uncertainty in California loads due to fluctuations in weather and economic conditions. This risk factor reflects the impact that the strength of the economy and fluctuations in temperature has on California loads and HLH and LLH spot market electricity prices. The level of economic activity impacts the overall annual amount of loads in California while fluctuations in load due to weather conditions cause monthly variation in loads, especially during the summer when cooling loads are highest. Load growth variability for California was simulated using annual variability parameters used as input data in PMDAM in the 1996 rate case and monthly load variability for California was derived from daily load variability parameters used as input data in PMDAM in the 1996 rate case. *See* Marginal Cost Analysis Study Documentation, WP-96-FS-BPA-04A.

Higher California loads increase the need to run thermal plants in California, which result in higher prices paid by California utilities for PNW surplus energy and higher prices paid by PNW utilities for purchased power from California. Conversely, lower California loads decrease the need to run thermal plants in California, which results in lower prices paid by California utilities for PNW surplus energy and lower prices paid by PNW utilities for purchased power from California.

2.4.7 Natural Gas Price Risk Factor. This factor reflects the uncertainty in the costs of producing electricity from gas-fired resources throughout the Western Systems Coordinating Council (WSCC) region. Higher than expected gas prices increase the cost of producing electricity from gas-fired resources, which increases the price of electricity on the spot market. Conversely, lower than expected gas prices decrease the cost of producing electricity from gas-fired resources, which decreases the price of electricity on the spot market.

Higher gas prices result in BPA earning higher surplus sale revenues and paying higher power purchase expenses. Lower gas prices result in BPA earning lower surplus sale revenues and paying lower power purchase expenses.

2.5 RevSim Analysis

For each of the 13 Fish and Wildlife Alternatives, including the five Fish and Wildlife Alternatives that reflect both an adjusted and unadjusted schedule, risk data were simulated by RiskSim to accommodate the calculation of 300 net revenues in RevSim for each fiscal year from FY 2002 - 2006. This process yields a total of 27,000 annual net revenues for these 18 fish and wildlife scenarios (18 fish and wildlife scenarios * 300 net revenues * 5 years). With the exception of differences in Federal hydro generation and AURORA spot market electricity prices resulting from changes in PNW hydro generation, the risk data for all the risk factors were the same for each of the fish and wildlife scenarios.

One of three sets of monthly prices from AURORA, modified downward under certain high streamflow conditions during April through June of the 50 water years, was used for calculating surplus energy revenues and power purchase expenses for each of the fish and wildlife scenarios. (*See* Chapter 1 of Risk Analysis Study Documentation, WP-02-FS-BPA-03A, Conger *et al.*, WP-02-E-BPA-41, at 7-11 and Conger *et al.*, WP-02-E-BPA-15, at 16-17 for a discussion on the adjustment of AURORA prices during April through June.) The set of spot market prices used for a particular fish and wildlife scenario was based on its impact on Federal hydro generation. (*See* Chapter 1 of Risk Analysis Study Documentation, WP-02-FS-BPA-03A, and Conger *et al.*, WP-02-E-BPA-15, at 13-14, regarding the use of three sets of spot market electricity prices from AURORA and which set of electricity prices were used for each of the fish and wildlife scenarios.)

The 27,000 annual net revenues simulated by RiskMod were provided to analysts that perform analyses with the ToolKit Model. ToolKit analysts subsequently selected a weighted sample of the net revenues for the five Fish and Wildlife Alternatives that have adjusted and unadjusted schedules in proportion to the likelihood of implementation from FY 2002 - 2006. After performing this task, 19,500 net revenues (13 Fish and Wildlife Alternatives * 300 net revenues * 5 years) from RevSim are used in the ToolKit Model to assess BPA's probability of meeting its annual U.S. Treasury payment on time and in full from FY 2002 - 2006. *See* Revenue Requirement Study, WP-02-FS-BPA-02.

2.6 Results from RiskMod

RiskMod results are used in an iterative process with the ToolKit Model and the RAM to calculate PNRR and, ultimately, rates that provide BPA with an 88 percent TPP for the five-year rate period. The net revenues estimated for each RiskMod run depend on the level of the PF and Industrial Firm Power (IP) rates developed by the RAM at different levels of PNNR. RiskMod estimates several temporary, intermediate sets of net revenues during the process of developing rates that yield an 88 percent TPP for the five-year rate period for both the Rate Design and Subscription steps in RAM. Given this situation, the only set of net revenues that represent the final set of net revenues from RiskMod are the net revenues that are estimated when the Subscription rates that yield an 88 percent TPP for the five-year rate period are input into RiskMod and RiskMod is run. A summary of the average annual net revenues for all 18 fish and wildlife scenarios for FY 2002 - 2006 from RiskMod using Proposed Rates is reported in Table 1. The net revenue risk estimated by RiskMod is an input into the ToolKit Model. The ToolKit Model uses the net revenue risk estimated by RiskMod, the net revenue risk estimated by the NORM model, and additional adjustments to net revenues from interest earned on cash reserves, and the CRAC to calculate TPP. *See* Section 2.2 of Revenue Requirement Study, WP-02-FS-BPA-02, Chapter 12 of Revenue Requirement Study Documentation, WP-02-FS-BPA-02A.

Table 1: Average Annual Net Revenues for 18 Fish and Wildlife Scenearios for FY 2002 - FY 2006

Net Revenues ($ Thousand)						
Scenarios	**FY 2002**	**FY 2003**	**FY 2004**	**FY 2005**	**FY 2006**	**5 Yr Average**
1 - In-River (low)	104,419	56,698	52,809	59,202	52,261	65,078
2 - In-River (hi) CWA	129,858	79,393	75,821	85,407	79,694	90,035
3 - Exp Trns	105,746	59,749	54,563	61,369	54,435	67,173
4 - Exp Trns (low)	111,022	84,824	79,277	86,250	76,643	87,603
5 - TrnsPlus	104,419	56,698	52,809	59,202	52,261	65,078
6 - TrnsPlus CWA	104,419	56,698	52,809	59,202	52,261	65,078
7 - 2 LSN	37,880	-20,404	-14,674	-14,191	-15,582	-5,394
8 - 4 LSN	11,410	-49,962	-43,975	-45,786	-46,315	-34,926
9 - LSN & JDA	10,182	-52,604	-47,015	-48,035	-50,211	-37,537
10 - JDA	104,419	56,698	52,809	59,202	52,261	65,078
11 - JDA Spillway	104,419	56,698	52,809	59,202	52,261	65,078
12 - LSN JDA Spillway	9,396	-52,420	-46,810	-48,107	-49,871	-37,563
13 - LSN & JDA CWA	-61,070	-133,535	-128,657	-127,388	-132,503	-116,630
14 - 2 LSN - Adj	99,427	51,284	47,681	53,405	46,501	59,660
15 - 4 LSN - Adj	99,140	50,983	47,356	53,095	46,185	59,352
16 - LSN & JDA - Adj	99,723	51,561	47,910	53,737	46,629	59,912
17 - LSN JDA Spillway - Adj	98,904	50,676	47,148	52,771	45,845	59,069
18 - LSN & JDA CWA - Adj	26,310	-34,884	-30,389	-29,521	-32,655	-20,228
The revenue requirement used in calculating these net revenues includes $99 million in PNRR.						

In Table 1, the average annual net revenues reported for each of the fish and wildlife scenarios have been calculated with $99 million in PNRR. The five-year, average annual net revenues from RiskMod ranged from a low of -$116.6 million for fish and wildlife scenario 13 (Snake River and John Day Dams to Natural River (high option) + Clean Water Act (CWA)), which reflects the unadjusted schedule, to a high of $90.0 million for fish and wildlife scenario 2 (In-River Migration (high option) + CWA). Additional information on the means, medians, standard deviations, and detailed statistics about the net revenue distributions as percentiles for each of the fish and wildlife scenarios are reported in Risk Analysis Study Documentation, WP-02-FS-BPA-03A.

A summary of Federal hydro generation (aMW) for all 18 fish and wildlife scenarios for FY 2002 - 2006 are reported in Table 2. A comparison of the net revenues reported in Table 1 and the Federal hydro generation (aMW) reported in Table 2 indicate that most of the differences in average annual net revenues between each of the fish and wildlife scenarios are due to differences in five-year, average annual hydro generation.

Table 2: Federal Hydro Generation (aMW) for 18 Fish & Wildlife Scenarios for FY 2002 - FY 2006

		Federal Hydro Generation (aMW)					
		FY 2002	FY 2003	FY 2004	FY 2005	FY 2006	5 Yr Average
1	In-River Migration (low option)	8500	8500	8500	8500	8500	**8500**
2	In-River Migration (high option) with CWA	8515	8515	8515	8515	8515	**8515**
3	Expanded Transport	8553	8553	8553	8553	8553	**8553**
4	Expanded Transport (low option)	8664	8664	8664	8664	8664	**8664**
5	Transportation Plus	8500	8500	8500	8500	8500	**8500**
6	Transportation Plus and CWA	8500	8500	8500	8500	8500	**8500**
7	Two Snake River Dams to Natural River	8500	8348	7890	7890	7890	**8104**
8	Four Snake River Dams to Natural River	8500	8341	7890	7732	7280	**7949**
9	Snake River and JDA Dams to Natural River	8500	8359	7887	7745	7274	**7953**
10	John Day Dam to Natural River	8500	8500	8500	8500	8500	**8500**
11	John Day Dam to Spillway Crest	8500	8500	8500	8500	8500	**8500**
12	Snake River Dams to Natural River and JDA Dam to Spillway Crest	8500	8337	7886	7724	7272	**7944**
13	Snake River and JDA Dams to Natural River (high option) plus CWA	8092	7965	7532	7404	6997	**7598**
14	Two Snake River Dams to Natural River - Adj. Sch	8500	8500	8500	8500	8348	**8470**
15	Four Snake River Dams to Natural River - Adj Sch	8500	8500	8500	8500	8341	**8468**
16	Snake River and JDA Dams to Natural River - Adj Sch	8500	8500	8500	8500	8359	**8472**
17	Snake River Dams to Natural River and JDA Dam to Spillway Crest - Adj Sch	8500	8500	8500	8500	8337	**8467**
18	Snake River and JDA Dams to Natural River (high option) plus CWA - Adj Sch	8092	8092	8092	8092	7965	**8067**
		8487	**8481**	**8463**	**8459**	**8394**	**8457**

3. ANALYSIS OF NON-OPERATING RISK

3.1 Overview

The NORM is being introduced in this rate case. NORM is a tool that was developed to capture risks other than operational risks in the ratesetting process. This model is an extension of the risk modeling that has been used in previous rate cases. It uses the same general simulation methodology and @RISK computer software package that is used in RiskMod.

Whereas RiskMod is used to quantify risks having to do with various economic and generation resource capability variations, NORM is used to model the impact on expected costs associated with a set of 16 distinct risks surrounding projections of non-operations related revenue or expense levels associated with the generation function in the revenue requirement. The full list of non-operating risks modeled in NORM, and the values defining their distributions, is presented in Table 3. For example, NORM quantifies the uncertainties related to achieving Cost Review Recommendations and paying fish and wildlife costs.

3.2 NORM

Using the revenue requirement expense levels as the base levels, NORM uses, as input, potential deviations from the base levels and the probabilities associated with those deviations. For example, the costs associated with the achievement of Cost Review Recommendation No. 9 are shown in Table 3 as follows:

Achievement of Cost Review Recommendation #9 re: Potential achievement of some legislative efficiencies (AEP)	70%	$0
	30%	$7M

Table 3: Inputs To Non-Operating Risk Model (NORM)

Input	Probability	Deviation ($ Millions)
Achievement of Cost Review Recommendation #1 re: Reduce staffing and support costs of power marketing and other PBL functions not directly related to operation of the Federal power system	25% 50% 25%	$0 –$4.5 –$8.9
Achievement of Cost Review Recommendation #6 re: development of a consolidated/integrated capital asset management strategy for the FCRPS: *managing COE/Bureau of Reclamation O&M expense*	15% 75% 10%	$0 -$5.7 -$18.7
Achievement of Cost Review Recommendation #6 re: development of a consolidated/integrated capital asset management strategy for the FCRPS: *enhancing COE/Bureau of Reclamation revenues*	50% 35% 15%	$0 $5 $15
Achievement of Cost Review Recommendation #7 re: WNP-2: Aggressive cost management, flexible response to market conditions – *O&M Expenses*	10% 40% 50%	$0 -$14 -$4
Achievement of Cost Review Recommendation #7 re: WNP-2: Aggressive cost management, flexible response to market conditions – *Revenue enhancements*	40% 40% 20%	$12 $7 $4
Potential for required increase in payments to WNP-2 Decommissioning fund	30% 50% 20%	$0 -$2 -$4
Uncertainty re: generation's costs for transmission, since transmission business line will reset rates before FY 2002	40% 20% 10% 20% 10%	$0 -$10 -$25 $10 $25
Achievement of Cost Review Recommendation #9 re: Potential achievement of some legislative efficiencies (AEP)	70% 30%	$0 $7
Achievement of Cost Review Recommendation #8 re: Reduction of administrative and other internal support service costs	10% 50% 30% 10%	-$1 -$2 -$4 -$7
Costs of separation	50% 30% 20%	$0 -$2 -$4
Conservation and Renewables "make good" funds for renewables and low income weatherization	25% 25% 30% 10% 10%	$0 -$1 -$2 -$3 -$4
Interest rate risk – Potential change in interest expense due to uncertainty re: interest rates (The risk is expressed in terms of percentage points of potential deviation from interest rates assumed for new obligations in the repayment study. *See* Volume 1, Chapter 6 of Documentation for Revenue Requirement Study, WP-02-FS-BPA-02A.)	5% 10% 20% 30% 20% 10% 5%	-2.00% -1.25% -0.75% 0.00% 0.75% 1.25% 2.00%

• Deviation from the weighted average (the point estimate included in the revenue requirement) of the 13 system configuration alternatives:
  • Corps plant investment related to fish and wildlife
  • "Other entities" O&M related to fish and wildlife
  • Deviation from the mean for BPA direct program costs
	Each alternative weighted equally	

This example shows there is a 70 percent chance that there will be no change from what is reflected in the revenue requirement, and a 30 percent chance that the costs will be $7 million lower than the revenue requirement base level, which can also be interpreted as a $7 million savings.

In NORM, the non-operational risks are modeled in two worksheets, one for fish and wildlife expense risks and one for all other included risks. Table 3 contains a summary of the deviations and probabilities of each risk included in NORM. Deviations are expressed in annual average amounts. Negative amounts indicate a decrease in net revenues (higher expenses or lower revenues). Positive amounts indicate an increase in net revenues (lower expenses or higher revenues). NORM performs a risk analysis on only the generation function. Thus, it does not include any risk associated with the transmission function.

As stated in Chapter 2 of this Study, there are 13 Fish and Wildlife Alternatives. The five alternatives involving breaching of dams have two different schedule variants ("unadjusted" and "adjusted") as described in DeWolf *et al.*, WP-02-E-BPA-13, resulting in a total of 18 fish and wildlife scenarios. NORM is run 18 times, once for each fish and wildlife scenario, producing 300 5-year games per scenario. Each time a game is run, NORM produces a set of deviations (from expected costs) that reflects the combined effects of the 16 non-operating risks. The BPA Fish and Wildlife O&M (also called Direct Program) costs that are included reflect a uniform probability of costing between $100 million and $179 million on average over the five-year rate period for all 18 fish and wildlife scenarios. Each game is assigned a random number expressed as a percentage, and the set of annual costs used in the five years for that game is selected based on the percentage. For example, suppose the random number for a game is 65 percent, meaning that the BPA Fish and Wildlife O&M cost for that game is 65 percent of the way along the scale from $100 million to $179 million. Then in each of the five years the cost number will be 65 percent of the way from the low case cost for that year to the high case cost for that year.

The 13 Fish and Wildlife Alternatives are given equal weighting, with adjusted schedules for each of the five dam breaching Alternatives receiving a 90 percent weighting and unadjusted schedules for each of the five dam breaching Alternatives receiving a 10 percent weighting. *Id.* To reflect this weighting, the adjusted and unadjusted schedule outputs for the five dam breaching Alternatives are merged. The 270 games from the adjusted schedule runs are combined with 30 of the unadjusted schedule runs. This makes a total of 300 games, which reflects the 90 percent weighting on the adjusted schedule and 10 percent weighting on the unadjusted schedule.

These 3,900 games, 300 for each of the 13 Fish and Wildlife Alternatives, are aggregated into a single file. When this file is later read by the ToolKit Model, each of the Fish and Wildlife Alternatives will be matched up with the corresponding Fish and Wildlife Alternative results from RiskMod so that a complete package of the four components of the Fish and Wildlife Alternatives are treated together. *See* Chapter 2 of Risk Analysis Study Documentation, WP-02-FS-BPA-03A, regarding NORM.

In testimony, BPA agreed to explore the risk that potential changes in functionalization of costs would affect its risk analysis. Lovell *et al.,* WP-02-E-BPA-40, at 15. BPA wanted to ensure that the risk was captured. *Id.* BPA has explored this risk, determined it to be small, and has concluded that its risk analysis, and in particular its analysis of the risk of changes in the level of PBL's transmission expense, adequately captures the functionalization of costs. Presently BPA includes planned net revenues for risk in its revenue requirement, which accounts for unforeseen risks. Documentation for Risk Analysis Study, WP-02-E-BPA-03A, at 171. Additionally, the

NORM model already includes risks related to “probabilities of the generation function’s transmission expenses deviating from the costs included in the revenue requirement.” *Id.* at 171, 179.